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TRANSPORTATION ENERGY SYSTEMS

ENERGY & ENVIRONMENTAL SYSTEMS DIVISION
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THE INDUSTRIAL DEMAND FOR WESTERN COAL
IN THE GREAT LAKES REGION

by

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Energy and Environmental Systems Division

September 1979

prepared for

Office of Maritime Technology
Maritime Administration
U.S. Department of Commerce
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PREFACE

This research was conducted for the program Evaluation of the Market Potential and Environmental Effects of Increased Western Coal Transportation in the Great Lakes and Northeastern U. S. Regions, and is the third publication completed that reports coal transportation demands to the eastern Great Lakes. This work was prepared for Dr. Daniel P. Maxfield, Office of Transportation Programs, Department of Energy, and Robert G. Christensen, Office of Maritime Technology, Maritime Administration, Department of Commerce. Special thanks are extended to many persons who contributed to various phases of the analysis and review, including Karen A. Barczynski, Sarah J. LaBelle and Rita E. Knorr.

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EXECUTIVE SUMMARY

The Great Lakes industrial coal market, though currently much smaller than utility use, is expected to grow rapidly. Industrial conversion from oil and gas to coal is a linchpin of the National Energy Act. Industrial coal use in the Great Lakes states is expected to grow by as much as three percent per year until 1985.

Although the potential for industrial coal use appears to be growing modestly, the share of this market captured by Western coal is critically affected by air quality regulations. Existing and projected ambient air quality violations in the vicinity of port cities will prohibit new coal use. This will be a particularly severe constraint in the center of the industrial core areas of Buffalo, Erie, Cleveland, Toledo, and Detroit.

In addition to ambient air quality problems, more stringent New Source Performance Standards may make it prohibitively expensive to burn coal. Even for large coal users that can better afford the high capital cost of sulfur control technologies, the economic advantage of Western coal may be minimal in comparison to locally available high-sulfur coal. This is because it costs just about as much to use a high-efficiency scrubber with low-sulfur coal as with high-sulfur coal.

Under a standard of 1.2 lb SO₂ per million Btu of heat input, Western coal can be expected to capture a large share of the new boiler market within 75 miles of the Great Lakes ports. With a sulfur standard more stringent than the above, the market for Western coal will vanish even for users immediately adjacent to the port.

Western coal is only attractive in the East due to its low sulfur content, which under some conditions allows the end user to avoid expensive sulfur control technologies. The stringency of New Source Performance Standards will determine the economic advantages of low-sulfur coal and hence the demand for Western coal in the East.

Other studies have concluded that the emission standards currently proposed by the EPA will result in the elimination of most demand for Western coal for the new utility boilers east of the Mississippi. Since utilities present the bulk of the potential market for coal, this represents a serious blow to the market potential for Western coal.

The Great Lakes shipping system represents the most economic way of moving coal from the Western states to major portions of the industrial Midwest and Northeast. The Great Lakes system can move coal to users in the vicinity of port cities at costs that are less than half the cost of the most economic rail route. In addition to low costs, the Great Lakes system appears to be reliable and have fewer adverse environmental and social impacts than all rail routes. The advantages of lake-borne shipments diminish roughly in proportion to the distance of the end user from the final port of destination.

The above conclusions hold for the near-term expansion of new industrial users. For controlling emissions on existing boilers, low-sulfur coal may be a desirable option. Moreover, in the longer term (after 1990), the relatively rapid escalation of mining costs in the East may once again create a favorable market for Western coal.

1 INTRODUCTION

An assessment of future industrial coal demand based solely on recent historical trends would show a steady decline in coal use within the Great Lakes Region. Such a trend runs contrary to the often-stated federal goal of reducing U.S. dependency on foreign oil. If U.S. dependency on oil imports is to be reduced, the industrial sector is the most economically and administratively feasible target for conversion from foreign oil and gas to domestic coal. Given that industrial coal conversion is a linchpin of any comprehensive federal energy plan, it seems inevitable that the decades of stagnation and recent years of decline in coal use by industry will be changed. However, as will be discussed in subsequent sections, there are significant constraints to industrial coal conversion. Within this setting of uncertainty regarding industrial fuel switching lies a second major question. What type and source of coal will be most economic for industrial coal users in the Great Lakes Region?

This report deals with the potential market for Western low-sulfur coal in the eight states bordering on the Great Lakes (New York, Pennsylvania, Ohio, Indiana, Michigan, Illinois, Wisconsin and Minnesota), referred to here as the Great Lakes Region. Emphasis will be on the near term, between now and 1990, and on those industrial areas within the region that historically have used a great deal of energy. Since the economic attractiveness of Western coal shipments appears greatest in and around the major port cities on the Great Lakes, this market analysis will focus on five major port areas: Buffalo, New York; Erie, Pennsylvania; Cleveland, Ohio; Toledo, Ohio; and Detroit, Michigan. Each port area includes the feasible geographic market for Western coal.

Potential coal demand in the vicinity of the ports is derived from a number of recent U.S. and regional forecasts of industrial coal demand. Demand levels associated with a continuation of recent demand trends (referred to in this report as the Reference Scenario) and the National Energy Plan (referred to as the NEP Scenario) have been estimated by the U.S. Department of Energy (DOE) and disaggregated to local Bureau of Economic Analysis (BEA) areas by Oak Ridge National Laboratory. These forecasts are reviewed in Section 3.

The estimated demand potential will be tempered by a number of environmental and transportation constraints. Section 4 contains a brief discussion of the primary constraints: (a) the non-attainment of ambient air quality standards in the vicinity of the ports; (b) the likely Environmental Protection Agency (EPA) reduction in allowable emission rates from industrial boilers; and (c) bottlenecks on Great Lakes shipment lines and on rail lines serving dispersed industrial coal users.

The penetration of Western coal into industrial coal markets in the eastern Great Lakes Region will be estimated for alternative scenarios concerning demand and the environmental constraints discussed earlier. These market penetration estimates will be derived from simulations using the Argonne Coal Market model. The scenario assumptions and the model description are contained in Section 5.

The final section of this report contains a summary of key findings on the potential demand for Western coal by industrial users in the Great Lakes. It also reviews the uncertainties regarding these estimates and speculates the implications of the research results.

This is one of three reports produced in this study; the other two survey potential utility demand for coal and assess the delivered costs of Great Lakes shipped Western coal to users inland from ports.^{1,2} The combined conclusion of all three reports is that no increase in Western coal shipments will be sufficient to require major capital investments in Great Lakes shipping facilities through the 1980s.

2 HISTORICAL PERSPECTIVE ON COAL DEMAND

Recent historical trends in industrial* coal demand provide remarkable support for the public policy rhetoric concerning the need for reducing our use of valuable petroleum resources. Despite the oil embargo of 1973-74 and the subsequent skyrocketing of real oil prices, embargo of consumption by the industrial sector steadily dropped from 4.37 quads in 1973 to 3.57 quads in 1977. Some of the decline can be attributed to large conservation gains made by industry in the use of boiler fuels. Total energy consumed by industry declined from 29.16 quads in 1973 to only 27.79 quads by 1977. But conservation alone cannot explain the drop in industrial coal use. Coal as a percentage of all industrial fuels dropped from 15% in 1973 to 12.8% in 1977. These trends in industrial coal use are shown in Table 2.1.

The region composed of states contiguous to the Great Lakes represents the heaviest concentration of industrial coal use. Over half of all U.S. bituminous coal consumption by industry takes place in the eight Great Lakes states (New York, Pennsylvania, Ohio, Indiana, Michigan, Illinois, Wisconsin, and Minnesota). Despite the traditional importance of coal in these heavily industrial states, the region's share of total U.S. industrial coal use has declined steadily since 1973. Table 2.2 shows the absolute coal consumption in the Great Lakes and Northeastern states dropping from 41 million tons in 1973 to just over 3.2 million tons in 1977. As a percentage of total U.S. industrial demand, the region's share dropped each year since 1973, from 56.1% in 1973 to 51.0% in 1977.

Table 2.2 also shows the annual level of coal demand by state. Except for the slight growth in demand for New York and Minnesota, demand levels dropped rather sharply in every other state. Table 2.3 shows the trends in annual rates of change in demand for the individual states in the Great Lakes Region. The annual rate of decline for the region as a whole was -6.3%. The highest rates of decline are shown by Michigan (-15.9%) and Pennsylvania (-11.6%). The declining demand in Pennsylvania, Ohio, and Michigan is especially significant since these three states have particularly favorable transportation economics for Great Lakes shipment of Western coal because of the available port sites in these states.

*The industrial sector includes the construction, manufacturing, agricultural, and mining sectors.

Table 2.1. Coal and total Energy Consumption by the Industrial Sector, 1973-1977 (10^{15} Btu)

Year	Coal	Total Energy Used	Coal as % of Total
1973	4.37	29.16	15.0
1974	4.05	28.46	14.2
1975	3.80	26.07	14.6
1976	3.78	27.82	13.6
1977	3.57	27.79	12.8

Source: Reference 3.

Table 2.2. Great Lakes States and New England Bituminous Coal Shipped to Industrial Users and Retail Dealers, 1973-1977 (10^3 short ton)

Area or State	1973	1974	1975	1976	1977 ^a
New England	171	228	162	108	132
New York	2,377	2,130	2,198	2,425	2,571
Pennsylvania	6,329	5,920	4,816	4,062	4,081
Ohio	10,402	12,384	9,079	8,329	9,123
Indiana	5,703	4,999	4,141	4,148	4,925
Michigan	6,515	4,792	4,145	4,115	3,607
Illinois	5,195	5,117	4,001	3,709	4,180
Wisconsin	3,073	2,659	2,224	2,325	2,253
Minnesota	1,217	1,214	1,294	1,227	1,232
Total Great Lakes	40,982	39,443	32,060	30,448	32,104
Total U.S.	73,095	70,585	58,761	57,339	63,000
Great Lakes as % of U.S.	56.1%	55.9%	54.6%	53.1%	51.0%

Source: Reference 4.

^aArgonne National Laboratory estimates.

Table 2.3. Great Lakes States and New England
Rates of Change in Industrial Coal
Demand, 1973-1977

Area	Annual Rate of Change, 1973-1977 ^a
New England	-6.7%
New York	2.0
Pennsylvania	-11.6
Ohio	-3.3
Indiana	-3.7
Michigan	-15.9
Illinois	-5.6
Wisconsin	-8.1
Minnesota	.3
Great Lakes Region	-6.3

^aBased on tonnage shown in Table 2.2

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3 RECENT FORECASTS OF INDUSTRIAL COAL DEMAND

3.1 OVERVIEW

This section will review a number of industrial energy and coal demand forecasts made since the oil embargo of 1973-74. The methods and assumptions used in these forecasts are dissimilar; nonetheless the forecasts are consistent in showing markedly decreased growth rates in industrial energy to 1990 in comparison with historical trends of the last 20 years. This decrease results mainly from price-induced conservation. It is within a setting of vigorous conservation practices and reduced rates of expansion in industrial output that coal must compete for its market share. Thus, the studies cited below show only modest gains in industrial coal demand in the short to mid term (before 1990).

The purpose of this section is to present several national and regional forecasts of industrial energy and coal demand. Forecasts for the U.S. and regions containing most of the Great Lakes States will be presented (Sections 3.2 and 3.3, respectively), followed by more localized demand, disaggregated to BEA regions (Section 3.4). This section concludes with a brief critique of the demand forecasts, with an emphasis on their utility for projecting demand in the Great Lakes Region.

3.2 SLOWDOWN IN TOTAL ENERGY DEMAND

Several long-term forecasts have been made of the industrial demand for energy. Table 3.1 illustrates that the consensus of these studies is that there will be modest growth of industrial energy demand over the next 10 years. The data contained in Table 3.1 represent the best approximations of the annual growth rates in total energy demand forecasted in each study. Precise and unambiguous comparisons are impossible because of varying definitions of the industrial sector, time intervals, and the treatment of feedstocks and purchased electricity. It should also be noted that these forecasts were based on a variety of methodologies, ranging from detailed econometric models to expert judgement. Wherever possible, two forecast scenarios are presented -- one representative of a continuation of recent trends (i.e., reference case) and the other representative of the effects of new federal initiatives as embodied in the National Energy Plan (NEP). The NEP specified energy use, conservation, and supply goals, and was outlined by the President in 1977. The NEP was modified a year and a half later and was presented as a set of five acts, which became the National Energy Act (NEA) of 1978. This report uses the projections reported in the NEP.

The DOE-PIES model projected the highest rate of demand growth for both the 1976-1985 period (3.0%) and the 1985-1990 period (3.5%). The 3.0% growth rate is surprisingly high when compared to the absolute declines in demand from 1973 to 1977. It is also much higher than the base-case scenarios in three of the other four studies. On the low end of the spectrum, the WAES study showed absolute declines in total industrial demand through 1985.

Overall, these studies manifest a high degree of uncertainty about energy consumption by industry. There is no agreement about the near term or

Table 3.1. Summary of Approximate Annual Growth Rates Forecasted for Industrial Energy Demand through 1990

Source of Forecast and of Publication	1976-1985	1985-1990
Data Resources, Inc. (DRI), 1977		
Control case ^a	0.9%	1.2%
Carter case ^b	0.1	0.4
EXXON Co., 1977	Roughly flat	3.1
Institute for Energy Analysis, 1976		
High scenario ^a	2.7	3.3
Low scenario ^b	2.7	2.3
Workshop on Alternative Energy Supplies (WAES), 1976		
Case D ^a	-.07	-
Case B ^b	-.9	-
U.S. Department of Energy, Project Independence Evaluation System (PIES) Model, 1978		
Mid-Range ^a	3.0	3.5

Source: References 5 and 6.

^aClosest approximation to Reference Scenario.

^bClosest approximation to National Energy Plan Scenario.

the 1985-1990 period, nor is there much agreement on the consequences of an energy future similar to that found in the NEP. This uncertainty about the growth in total energy demand by industry is amplified in forecasts of regional coal demand.

3.3 REGIONAL DEMAND FOR COAL

There have been few formal efforts to forecast industry's demand for energy or for coal, specifically. However, work done by Brookhaven National Laboratory and by the U.S. Department of Energy (DOE) has addressed the question of interfuel substitution by industry in various multistate regions of the U.S.^{6,7} Both sets of forecasts are based on similar econometric models. Since these models take into consideration the relative growth rates of industrial output and fuel prices among regions, they contain more accurate guidance on the future demand for coal in the Great Lakes Region than could be obtained from an aggregated national analysis.

The Brookhaven demand projections were done separately for the five most energy-intensive industries in the northeast: food products, paper, chemicals, stone and glass, and primary metals. In 1974, these five industries accounted for over 70% of total energy use by industry in the northeast. Forecasts to 1985 were developed for three alternative policy scenarios:

1. Base Case: Represents the implications of all major federal policies existing prior to the National Energy Plan (NEP).
2. Initiatives Case: Driven by the regulatory changes and fuel price increases associated with full implementation of the NEP.
3. Strong Shift Case: Not directly related to either of the above policy alternatives; it is driven by a doubling of real oil prices to industry by 1985.

Results of this study are presented in Table 3.2. This table shows that, for the energy-intensive industries, total energy demand grows more rapidly for every scenario in New England vis-a-vis the Middle Atlantic Region. The Base Case and Initiatives Case are roughly similar in both regions; major changes in total demand occur in the Strong Shift Case.

For coal demand, all three scenarios show significant differences. The Base Case shows an actual decline in coal demand for New England, and only a moderate (0.7%) growth for the Middle Atlantic Region. In the Strong Shift Case, coal demand grows by an amazing 28.5% per year in New England and 9.0% in the Middle Atlantic Region. Surprisingly, the Initiatives Case shows a slight decline in the demand for coal in the Middle Atlantic Region. Of greatest significance to this study is the fact that, under the two most plausible scenarios (Base Case and Initiatives), coal demand in the Middle Atlantic Region grows only slightly or actually declines. The western edge of the Middle Atlantic region comprises a major part of the potential market for Western coal shipped on the Great Lakes.

The DOE-PIES model forecasts regional energy demand by end use sector and by fuel type for the ten federal regions. Table 3.3 contains the DOE-PIES forecast of steam coal demand for the four regions including the Great Lakes states, for the "Mid-Range/Trendlong Scenario," which is comparable in intent, but not in detail, to the Brookhaven Base Case. More specifically, the DOE scenario assumes moderate growth in real energy prices and no new federal policies. The DOE-PIES model has regions defined to cover the entire U.S. Thus, it is possible to show demand from the Midwest, which is now and will continue to be for the foreseeable future, the nation's largest coal demand area.

Unlike the Brookhaven projections, which include only steam coal demand, the DOE-PIES projections were made for demand for both steam generation and metals manufacture, as shown in Table 3.3. Metals manufacture requires the use of a particularly high grade of coal not found in western mining areas likely to utilize Great Lakes shipping. Thus, the steam coal market defines the market potential for Western coal. According to the DOE-PIES model, the steam coal market will continue to be miniscule in New England (100,000 ton/yr) to 1990. The largest market for industrial steam coal will be the Midwest which is projected to use almost three times the cumulative demand of the other three regions. The relative share of steam coal demand in each region does not appreciably change between 1985 and 1990.

Table 3.2. Brookhaven Projections of Demand for Steam Coal and Total Energy Demand by Energy-Intensive Components^a of the Industrial Sector (10¹² Btu)

Region	1985 Base Case	Annual Change 1974-85	1985 Initiatives Case	Annual Change 1974-85	1985 Strong Shift Case	Annual Change 1974-85
<u>Steam Coal</u>						
New England ^b	2.7	-0.6%	5.2	5.4%	45.7	28.5%
Mid-Atlantic ^c	198.7	0.7%	183.4	-0.1%	513.8	9.0%
<u>Total Energy</u>						
New England	245.1	1.8%	230.8	1.2%	217.4	0.7%
Middle Atlantic	1243.9	-	1124.2	-0.1%	1287.2	0.3%

Source: Reference 7.

^aIncludes the food products, paper, chemicals, stone and glass, and primary metals industries.

^bConnecticut, Maine, New Hampshire, Rhode Island, and Vermont.

^cDelaware, Maryland, New Jersey, New York, Pennsylvania, and District of Columbia.

Table 3.3. DOE-PIES Projections of Industrial Demand Metallurgy Coal and Steam Coal -- Mid-Range/Trendlong Scenario (10⁶ short ton/yr)

Region	1985			1990		
	Met.	Steam	Total	Met.	Steam	Total
New England ^a	0	0.1	0.1	0	0.1	0.1
New York/New Jersey	5.8	3.0	8.8	6.1	3.4	9.5
Mid-Atlantic ^b	37.4	13.4	50.8	39.2	15.1	54.3
Midwest ^c	37.0	47.0	84.0	39.0	52.1	91.1

Source: Reference 6.

^aConnecticut, Maine, Maryland, New Hampshire, Rhode Island, and Vermont.

^bPennsylvania, Delaware, Maryland, Virginia, District of Columbia, and West Virginia.

^cOhio, Indiana, Illinois, Michigan, and Wisconsin.

Table 3.4 contains data on annual growth rates in demand by region for the DOE-PIES Mid-Range Scenario which can be usefully compared to the Brookhaven data in Table 3.2. The reader is cautioned, however, that neither the scenario assumptions nor the regional boundaries correspond exactly.

The DOE and Brookhaven projections are in agreement that coal demand will grow less rapidly in New England than in the combined Mid-Atlantic/New York-New Jersey region. In fact, both studies project a decline in coal use for New England in their respective 1985 base cases. The Brookhaven study is more optimistic about the potential growth of coal demand in the Mid-Atlantic/New York-New Jersey regions, projecting a small annual growth, compared to small to sharp declines for the same general area in the DOE study. This apparent contradiction is even more puzzling when one examines the rates of growth for total energy demand. Although Brookhaven has a larger coal demand growth, it has a much lower forecast of total energy demand (zero compared to 2.5-4.5% for DOE). It is likely that the Brookhaven model allows for a much greater industrial interfuel substitution response to relative fuel prices.

The above comparisons of demand projections for total energy and coal demand reveal a great deal of uncertainty about the energy futures for the nation and for the Great Lakes Region. The selection of any particular forecast can be disputed. For the purpose of this study we have selected the DOE-PIES Mid-Range Scenario as our Reference Scenario. We have done so for three reasons: (1) it was generated by a widely recognized methodology; (2) it was generated with relatively great regional sensitivity; and (3) it assumed moderate changes in fuel prices and federal policies. The scenario assumptions will be modified in a subsequent sensitivity analysis.

Table 3.4. DOE-PIES Projections of Industrial Demand for Steam Coal and Total Energy Demand -- Mid-Range/Trendlong Scenario (10^{12} Btu)

Region	1985				1990			
	Demand for Coal	Annual Change 1977-85 (%)	Total Energy	Steam Coal as a % of Total	Coal	Annual Change 1985-90	Total Energy	Steam Coal as a % of Total
New England	2.8	-5.1	484.1	5.8	3.2	2.7	572.0	3.4
New York/ New Jersey	70.0	-5.0	950.0	4.5	79.6	2.6	1089.2	2.8
Mid-Atlantic	312.2	-0.6	2628.2	2.5	356.3	2.7	2950.6	2.3
Midwest	1178.8	7.4	4831.8	2.0	1308.1	2.1	5516.2	2.7

3.4 BEA LEVEL DEMANDS

The DOE-PIES model results contained in Table 3.3 have been disaggregated by Oak Ridge National Laboratory coal demand estimates for industry in each Bureau of Economic Analysis (BEA) region. Each BEA region covers several counties (some of which are semi-urban or rural) that often cross state lines. These estimates are bound to historical relationships between industrial output and coal use. If technological, economic, or environmental factors change these relationships, the forecasts will be invalidated. This brings up a critical problem in the assessment of a potential coal market accessible by Great Lakes shipment. If potential coal users find that air quality restrictions in industrial use areas require costly pollution control measures, they may find it to their advantage to locate in more rural areas where environmental problems are not a source of economic penalties. It is beyond the scope of this analysis to address the issue of increased industrial ruralization. While recognizing the potential for major shifts in location patterns, we will accept the forecasts of industrial activity by BEA region developed by Oak Ridge National Laboratory to derive their coal use estimates. This assumption still allows for relocation of industry from the densely concentrated non-attainment areas* to rural areas in the same BEA region.

The estimates of total coal demand by industry are contained in Table 3.5 for each of the five BEA regions with major port facilities. The demand estimates are given for 1985 and 1990 and for the Reference Scenario and the NEP Scenario. Under the more optimistic Reference Scenario, the level of total coal demand for all five BEA regions in the year 1985 is 709.8×10^{12} Btu (about 28.3×10^6 ton of western coal). Assuming that the projections and regional disaggregations are correct, the total market for coal from new and existing users lies in the range of 28 to 41×10^6 ton of western coal in 1985. This can be regarded as the maximum volume of western coal that could be used in the Great Lakes Region.

This maximum market for western coal is further limited by the cost of the second transshipment at the destination port. In addition, problems with meeting air emission restrictions limit the prime market areas near the port cities. Thus the reasonable market for western coal in the Great Lakes States is much smaller than the total forecasted demand in those states.

The disaggregation to BEA regions by Oak Ridge National Laboratory (Table 3.5) did not maintain the distinction between metallurgical and steam coal use by industry shown in Table 3.3. These values greatly overestimate the potential market for western coal because they include metallurgical coal demand. In order to break out the portion of total coal demand that is for steam coal, we were forced to use the state level ratios of steam coal to total coal use in 1975 listed in Table 3.6.

Applying the percentages listed in Table 3.6 to the BEA level data in Table 3.5 provides an estimate of the amount of steam coal projected for

*A non-attainment area is an Air Quality Control Region not meeting National Ambient Air Quality Standards for a specific pollutant.

Table 3.5. Projected Total Coal^a Demands for BEA Regions Surrounding Major Great Lakes Port Cities (10¹² Btu)

Port City	1985		1990	
	Reference Scenario ^b	NEP Scenario ^c	Reference Scenario ^b	NEP Scenario ^c
Buffalo, New York	48.0	50.0	49.6	72.2
Erie, Pennsylvania	50.7	30.5	56.9	43.3
Cleveland, Ohio	313.5	190.3	335.8	235.1
Toledo, Ohio	56.6	52.8	60.3	69.9
Detroit, Michigan	241.0	166.5	262.9	231.2
Total	709.8	490.1	765.5	651.7
Equivalent weight of western Coal (10 ⁶ ton)	41.0	28.3	44.2	37.7

^aIncludes metallurgical and steam coal.

^bBased on the DOE-PIES Mid-Range/Trendlong Scenario.

^cBased on the DOE-PIES National Energy Plan Scenario.

Table 3.6. Steam Coal and Total Coal Use (10¹² Btu) for Selected Great Lakes States

	Coal Demand		Steam Coal as % of Total
	Total Coal	Steam Coal	
New York	158.4	64.2	40.5%
Pennsylvania	772.0	156.1	20.2
Ohio	572.8	218.2	38.1
Michigan	255.0	110.7	43.4

Source: Reference 4.

use in each BEA region. These are liberal estimates for Buffalo and Cleveland, which have heavy concentrations of steel-making relative to their respective states, and therefore heavy use of metallurgical coal. These adjusted demands are shown in Table 3.7.

Of particular note in Table 3.7 is the small incremental demand in both 1985 and 1990 for the combined five-port area. The growth in coal demand from 1974 to 1985 is only 2.1×10^6 ton of western coal in the Reference Scenario, and a decrease of 1.9×10^6 tons in the National Energy Plan Scenario. The incremental growth in demand between 1974 and 1990 is not substantially higher. This incremental demand measure is smaller than the actual market potential for new coal sources because it does not include fuel

Table 3.7. Adjusted Estimated Industrial Steam Coal Demand for BEA Regions Surrounding Major Great Lakes Port Cities (10^{12} Btu)

Port City	1985		1990	
	Reference Scenario	NEP Scenario	Reference Scenario	NEP Scenario
Buffalo, New York	19.4	20.2	20.1	29.2
Erie, Pennsylvania	10.2	6.1	11.5	8.7
Cleveland, Ohio	119.2	72.5	127.9	89.6
Toledo, Ohio	8.2	20.1	23.0	26.6
Detroit, Michigan	<u>104.6</u>	<u>72.3</u>	<u>114.1</u>	<u>100.3</u>
Total	261.6	191.2	296.6	254.4
Equivalent weight of western coal (10^{12} tons)	15.1	11.1	17.1	14.7
Incremental demand growth from 1974 (10^6 tons of western coal)	2.1	-1.9	4.1	1.7

switching by pre-1974 boilers. This type of switching from eastern bituminous to western subbituminous coal cannot be achieved without boiler modifications and partial deratings. Thus, it will be generally limited to newer boilers. Considering the advanced age of the capital stock in these industrial areas, coal switching is likely to significantly augment the maximum growth indicated at the bottom of Table 3.7.

4 MAJOR CONSTRAINTS TO COAL USE

In comparison to oil and gas, coal has always suffered from material handling problems and from the large size and complexity of its combustion devices. These technical difficulties have, since the passage of the Clean Air Act Amendments in 1970, been compounded by the environmental constraints associated with coal combustion, particularly from small, urban sources. Increased coal combustion creates air emissions problems, as well as substantial problems in solid waste disposal. These environmental impacts vary enormously from locality to locality. They will be important constraints in the future growth and regional distribution of coal combustion.

This section discusses the implications of the two most critical constraints on western coal use in the Great Lakes Region: air quality and transportation. The preservation and enhancement of air quality imposes major restrictions on coal users by requiring the use of emission control technology on major users and by limiting plant location choices based on county classification regarding attainment of air quality standards. Section 4.1 contains a discussion of the effects of current and possible future regulations including the results of a recent Argonne National Laboratory (ANL) study at the national level.⁸ Transportation constraints for industrial users of coal will be reviewed in Section 4.2. The environmental and transportation constraints described in this section have been examined for their effects on coal markets using a simulation model developed at ANL; this analysis is presented in Section 5.

4.1 AMBIENT AIR QUALITY CONSTRAINTS

The economic burden of controlling the emissions from coal varies enormously from locality to locality. In areas that have ambient air quality that is out of compliance with federal or state standards, the costs of controlling incremental emissions, and hence the cost of coal use, are extremely high. In such areas, new coal combustion sources must not only meet the lowest achievable emission rate (by using low-sulfur coal plus scrubbers), but must also find other local sources that will reduce their emissions enough to provide equivalent pollution offsets. The institutional and legal entanglements of this "offset policy" may indeed be more costly than the control technologies themselves. Virtually no documented cases exist of successful pollution offset trades between independent firms.

On the other end of the air pollution spectrum are those areas that are well within compliance with prevailing ambient standards. In these areas, large industrial sources must meet only the prevailing emission standards for large new sources. Small industrial plants (less than 250 million Btu/hour heat input) are generally given wider latitude in selecting fuels and controlling emissions. Many states allow small boilers to burn virtually any coal without sulfur emission controls of any sort. If such laws were to remain intact, there would be an overwhelming difference in environmental control costs between non-attainment and attainment areas of medium to small users of coal.

A recent ANL study⁸ of the local air quality impacts of increased coal combustion helps to identify both the magnitude and geographic location of ambient air quality constraints on coal use. The study focused on the increased levels of coal combustion projected from the National Energy Plan. The implications of local SO₂ and Total Suspended Particulates (TSP) impacts resulting from the assimilation of coal use projected for 1985 and 1990 are analyzed to determine if conflicts will arise between NEP goals and air quality regulations. Only the impacts resulting from the use of coal in new facilities are considered. Areas where air quality regulations are most likely to be jeopardized because of projected coal use are identified on the basis of a county level analysis for the entire United States. The amount of coal potentially constrained in both the industrial and utility sectors is also evaluated for both 1985 and 1990.

The approach used by Argonne to identify county-level air quality siting constraints from projected coal-burning facilities begins with a county-level scenario of coal use in the utility and industrial sectors for the years 1985 and 1990. This reflects increased coal consumption above current levels as prescribed by the National Energy Plan. Industrial coal use for 1985 and 1990 was provided by Oak Ridge National Laboratory on a BEA area level, and disaggregated by Brookhaven to the county level.

For each county, the air quality increment from new coal use in 1985 and 1990 was compared to the available air quality increment. Generally, this was the Class II Prevention of Significant Deterioration (PSD) increment, although in some cases the 1975 air quality was sufficiently close to the National Ambient Air Quality Standards that less than the entire Class II increment was available for new sources. Counties containing new industrial coal use but lacking 1975 air quality data were assumed to be capable of assimilating all of the projected coal-related emissions. This assumption is made because most air quality problem areas are recognized and monitored by state environmental agencies. Counties in which the allowable increment was exceeded by coal use were assumed to assimilate only that amount of coal use that would allow them to remain in compliance with the allowable increment.

The assessment of impacts to local air quality was inherently limited to a county-level analysis because of the county-level nature of the siting data. Important factors relating to local air quality levels such as the precise siting of a potential emitter, interactions with other emitters, local topography, and unique meteorological conditions cannot be fully accounted for in a county-level approach. However, the study does provide an indication of those areas constraining new siting and the severity of these constraints. It further identifies those counties that may have difficulties in assimilating the level of coal use projected for them. The study also estimates the total amount of coal use affected by air quality regulations in the industrial and utility sectors for both 1985 and 1990.

The by-products of coal combustion used in industrial processes constitute a significant contribution to air pollutant emissions in many urban areas. Of greatest importance are the sulfur dioxide (SO₂), particulates (TSP), and oxides of nitrogen (NO_x) emissions from stacks. Industries over a certain size (measured by annual pollutant emissions) are now subject to stringent regulations concerning environmental control technologies to modify emissions and location of the plants with respect to other emitters in an

area. Combustion is the primary source of SO₂; electric utilities are the other principal combustion source and are also subject to stringent regulations. There are many sources of TSP beyond combustion processes, however, including unpaved roads and extraction and mining processes. NO_x is produced by stationary and mobile combustion sources, i.e., industrial and utility plants, and automobiles, respectively. In general, SO₂ and TSP emissions are more stringently regulated for stationary sources; NO_x emissions from mobile sources are also stringently regulated. The following subsection defines the legislative and regulatory structure that is charged with improving and maintaining air quality, and the current process that is likely to affect industrial coal users, particularly in the Great Lakes Region.

4.1.1 Air Quality Laws and Regulations

The Clean Air Act Amendments of 1970 began a new era, with particular effects on industrial coal users, among others. EPA was required to develop and enforce regulations aimed at improving the quality of ambient air, particularly in urban areas. The first step in that process was the identification of criterion pollutants, high levels of which adversely affected public health. Six such pollutants are identified in the National Ambient Air Quality Standards (NAAQS): SO₂, TSP, NO_x, hydrocarbons (HC), carbon monoxide (CO), and photochemical oxidants (O_x). Allowable concentrations of each of these pollutants, and the time basis for the measurement, are set out in the NAAQS.

Measurements taken in urban and rural areas indicated that large portions of the population were exposed to hazardous levels of all or some of these pollutants. Regulations to identify and classify areas of the country in need of specific actions to improve air quality were promulgated. States were required to develop and implement plans that classified state lands by county or subcounty area, regarding attainment and maintenance of the NAAQS. Steps toward the national goal of clean air must be indicated before the State Implementation Plans (SIPs) are submitted to the EPA for approval. SIPs were required to be at least as strict as federal regulations for ambient air quality and for point or stationary source emissions. SIPs were to demonstrate compliance with the NAAQS between 1975 and 1977. When many states either could not develop adequate SIPs, or successfully implement their plans, Congress then developed further amendments to the Clean Air Act in response to the difficulties that EPA and the states had experienced in meeting the goals of the 1970 amendments.

The Clean Air Act Amendments of 1977 extend the deadlines for compliance with the NAAQS to the end of 1982. Other provisions of the 1977 amendments require EPA, among other things, to:

- Review the NAAQS periodically.
- Promulgate updated versions of the New Source Performance Standards (NSPS) regulating air pollutant emissions from stationary sources.
- Classify areas of the country regarding Prevention of Significant Deterioration (PSD), as well as attainment and non-attainment of air quality.

- Promulgate regulations regarding air quality and impairment of visibility in PSD areas.
- Determine Best Available Control Technology (BACT) and Lowest Achievable Emission rate (LAER) for new coal-burning sources.

Each of these requirements has significant impacts on coal-burning industrial plants.

The review of the NAAQS, which include updated health effects data on which the standards are based, also includes development of several new standards specifically required in the 1977 amendments. These are for sulfates, fine particulates, a one-hour standard for NO_2 , and visibility regulations. New coal-burning sources will have to comply with those regulations when they are promulgated.

The new NSPS for fossil-fired steam generators, proposed for EPA in November 1977 in response to the Congressional mandates, have stirred considerable controversy, and have not yet been finally promulgated. The EPA proposal for NSPS, the least stringent requirements that could be placed on such plants, called for 90% removal of sulfur emissions regardless of the sulfur content of the coal in the new boiler, between floor and ceiling values that were set such that any U.S. coal use would require scrubbing the stack gases. Recent drafts of the regulations have suggested 5% removal; controversy still remains, however, as many parties (including industries, utilities and the Department of Energy) urge that the standard be restructured to require a sliding scale of sulfur removal based on the initial sulfur content of the coal. Such a regulation could be specified to permit less than full scrubbing when relatively low-sulfur coal is used in the new plant. To date the EPA has not promulgated final regulations resolving the debate.

The proposed NSPS will have a different magnitude of impact on smaller industrial coal users than on larger users. EPA is likely to set standards on the now virtually unregulated small users having boilers rated less than 250 million Btu/hour. Standards may be set between 0.5 and 0.8 lb $\text{SO}_2/10^6$ Btu. This would drastically increase their emission control costs and probably alter their choices among coals of different sulfur content. The effect of emission controls on a large utility plant would be about \$12-14 per ton of high-sulfur coal; by contrast, a small industrial plant would experience two to three times as much cost on the same basis. This provides a motive for the smaller plants to avoid the use of high-sulfur coals.

BACT is developed on a case-by-case basis by permitting agencies, which balance energy, environmental and economic impacts. The 1977 amendments called for states to require the best system of continuous emission reduction on new or modified coal-fired steam generators. BACT must be specified to result in emissions at least as low as NSPS, and can potentially be much stricter. BACT is applicable in attainment areas, i.e., areas desiring to preserve their existing air quality which is in compliance with the NAAQS.

In non-attainment areas, the Lowest Achievable Emission Rate (LAER) must be defined, and applied to all new sources. LAER must also be at least as strict as the NSPS. LAER will also be applied to major emitters locating

just outside of non-attainment areas. Non-attainment areas are also subject to EPA's offset policy. New sources of pollutants must provide decreases in emissions equal to or greater than their proposed increment to regional emissions of that pollutant, in addition to meeting the LAER requirement. To date there is no record of a successful tradeoff between independent firms. Intra-firm tradeoffs have occurred, however. The institutional constraints posed by the offset policy may prove costly to industrial users.

The PSD regulations have a potentially large impact on new coal-burning industries' decisions on plant location. Areas in compliance with the NAAQS, as of the August 7, 1977, baseline for the SIPs, have been further classified as PSD-Class I, II, or III. For each of these classes, EPA has promulgated regulations (for SO₂ and TSP to date) specifying the incremental increase in the concentration of those pollutants above existing (1977) levels. Class I areas are intended to remain pristine; the increments are so small as to preclude the location of any major industrial source of air pollution in or near those areas. Most PSD-Class I areas are located in the west and southwest regions of the U.S., often coinciding with large national parks and wilderness areas. Attainment areas not designated as mandatory Class I areas were automatically designated Class II areas, with discretion left to the state whether to keep that designation or reclassify the area to Class I or III. Classes II and III allow progressively larger increments in the additional concentrations of pollutants (set for only SO₂ and TSP to date), effectively allowing more new industrial or utility development to locate in those counties (classifications are specified at least at the county level).

4.1.2 Identification of Air Quality Constrained Counties

These requirements set by the Clean Air Act Amendments of 1977 clearly have impact on both industrial and utility decisions on expansion of existing plants, location of new plants, and choice of process technology relating to the amount of coal burned, if any, and pollutant production measured at the stack and nearby the plant. The effects have been evaluated to an extent by a recent national study undertaken by the national laboratories for DOE, called the National Coal Utilization Assessment (NCUA).⁸ The NCUA identified the possible effects of the National Energy Act (NEA), which calls for increased use of coal by industry and electric utilities. Although the study identified and assessed many potential impact areas (water quality and solid waste disposal for example), the air quality impacts are the most constraining and are thus the focus of this discussion. The NCUA air quality assessment, with the exception of long-range transport effects, was prepared by Argonne National Laboratory staff for the whole nation, using techniques appropriate to the scale and timing of the overall assessment.

The NCUA began with the DOE-PIES energy demand forecasts mentioned earlier, and used the county-level disaggregation by Brookhaven National Laboratory, also discussed in Section 2, for industrial energy demand. Then, on a county basis, forecasted industrial growth and the associated emissions were compared with the county's air quality status. Non-attainment counties for SO₂ were assumed to pose a constraint to all new growth in coal use, subject to the flexibility of emission offset policy now in effect. (This allows growth in a non-attainment area if another pollutant source can be cleaned up by an amount greater than the new source's expected emissions, in a

tradeoff arrangement.) Attainment counties were assumed to pose a constraint to development in PSD-Class I areas. Industrial growth in PSD-Class II or III areas is partially constrained, depending on the competition from other new sources (e.g., electric power plants) and the pollutant which is closer to violation in that county -- SO_2 or TSP. A simple proportional model, relating the ratio of baseline emissions and air quality to the ratio future emissions and air quality was the basis for this analysis. Thus, if the new emissions from a forecasted industry did not put the county over the NAAQS for SO_2 or TSP using the proportional model, the industrial growth was considered to be assimilated into the county.

If the new emissions yielded an increase in ambient concentrations above the NAAQS, the forecasted growth was considered to be potentially constrained, subject to the offset policy and other local conditions. A summary of the number of the counties nationwide with forecast industrial growth and the kinds of air quality constraints on location is presented below, assuming SO_2 is the limiting pollutant:

	<u>Number of Counties</u>
All forecasted industrial growth assimilated	383
Some growth potentially constrained	185
All growth constrained	144
Total counties with forecasted industrial growth	712

Figure 4.1 displays the regions defined for use by the national labs in the NCUA to assess the effects of the NEP. These regions correspond to those in the Appendix, Tables A.1 and A.2, displaying the regional distribution of potential constraints on new industrial coal use, assuming the Brookhaven disaggregation of the NEP forecasted levels of industrial growth in coal demand.

The category "all forecasted industrial growth assimilated" includes only the attainment subheading of PSD-Class II, NAAQS Maintained. The attainment subheading of Exceeded for TSP Only and Non-attainment-TSP Only are summed to the category "some growth potentially constrained"; and the remainder constitute the category "all growth constrained." The NEP study regions shown in Figure 4.1 do not coincide exactly with the Great Lakes Region, but the results for the Midwest and Northeast NEP regions do include all Great Lakes states. Further analysis of the effects of these constraints on Great Lakes states' industry is presented in Section 5.4, based on results of the Argonne Coal Market model. The Brookhaven model projects growth in counties regardless of air quality constraints in the Midwest and Northeast; therefore, coal-using industries projected in this manner may be overstated.

The limitations of the NCUA analysis of the NEP effects need to be mentioned here. First, local air quality effects have not been considered in the constrained analysis; and second, the analysis for industrial coal users does not forecast the response of industry to these new regulations because the Brookhaven method is based on historical relationships between regional

Fig. 4.1. National Coal Utilization Assessment Study Regions
for the National Energy Plan

economic activity and industrial coal use. Regarding the first limitation, many plants could be sited in areas marked as constrained or partially assimilating growth if local conditions (meteorology, location of other sources) allow or emission offsets are available. The extent to which this could affect the results has not been estimated.

The second limitation is significant and points to the basis for future research relevant to impacts of coal use on the Great Lakes. The analysis by the NCUA for electric utility siting did, by contrast, include some of the reactions by utilities to the current and possible future regulatory situation by starting from a data base that included utilities' plans for new capacity. Electric utilities are most needed to serve demand in densely populated areas, corresponding almost perfectly to the non-attainment counties (all industrial coal growth constrained). The utilities have some flexibility to locate in adjacent counties by relying on cables to cover the distance to the load center. Current utility expansion plans, filed with the Federal Energy Regulatory Commission (FERC), provide a more sophisticated and accurate data base to begin a constraint analysis. Industrial coal users are not uniformly required to provide such advance notice of construction plans; some type of location modeling effort is required to simulate and then forecast possible patterns of industrial location incorporating the new EPA emissions regulations.

4.2 COAL TRANSPORTATION

Coal taxes the transportation system more than any other primary energy source. Coal is abrasive, heavy, and non-homogeneous, thus making it very costly to move on a Btu basis. For this reason, coal users pay a higher proportion of their total delivered cost for transportation than do users of any other fuel. Well over half the cost of western coal delivered to the Midwest is in transportation. Because transportation adds so much to the cost of coal and places such great demands on transportation networks, it is critical to the market potential of western coal.

This section treats the Great Lakes coal transportation system according to its three separate components:

1. The rail segment from minemouth to the transloading facility at Superior, Wisconsin.
2. The water segment from Superior to the port of destination.
3. The rail or truck distribution system from port to final user.

The mainlines from the Montana coal fields to Superior are well maintained, high-volume routes. They are owned by the relatively prosperous Burlington-Northern (BN) Railroad. Since 1970, the BN has experienced a boom in its freight loadings, which has greatly increased its revenue growth and enabled it to be an industry leader in capital investments for facility improvements.

Rolling stock represents a potential constraint to a major increase in the volume of coal shipments. About 100 unit train sets (100 cars plus

three locomotives) now serve the coal shipment from the Northern Great Plains. This number must be more than doubled to meet the minimally expected increases by 1985, i.e., over 10,000 cars must be added to the system. Shortages of hopper cars have been particularly severe in the Appalachian mining districts. The BN experiences its worst shortages of train capacity during the fall harvest season. The causes of these local and/or seasonal shortages are not related to any physical constraints on the capacity to produce new hopper cars or locomotives. Recent studies of the rail industry have uncovered no inability of the equipment supply industry to meet demand, given reasonable lead times for delivery.^{8,9}

Since this line traverses some of the least populated portions of the U.S., many of the adverse social and environmental impacts of frequent unit train operations are mitigated. These adverse impacts, including noise, vibrations, crossing delays, accidents, and the disturbance of wildlife habitat, are very real issues throughout much of the West. The Great Lakes system has a decided advantage in this regard.

In summary, the rail segment closest to minemouth operations does not appear to pose problems for increased shipments. The track is well maintained and currently has excess capacity. Research is underway for the development of more lines if the goals of the NEP are fulfilled. Moreover, Burlington-Northern could easily obtain the necessary rolling stock and personnel inputs to further expand shipments. Local resistance to increased train movements is apt to be relatively small.

The first movement of western coal on the Great Lakes came as a result of Detroit Edison's decision to burn low-sulfur coal from Decker, Montana, in its St. Clair plant. In 1973, this movement began with only 130,592 net tons, but grew to almost four million tons by 1977. Based on Detroit Edison's experience, the waterborne segment of the coal shipment system is comparatively low-cost and not disruptive to third parties. Technological improvements in loading and vessel design expedited this first movement of western coal on the Great Lakes. The transloading facility at Superior, Wisconsin, is the largest and most efficient in the world. In addition, new super 1000-ft colliers were built that maximize the tonnage that can be carried on the Great Lakes.

Though no significant increase in western coal shipment is expected in the next decade, it is worth noting that three apparent constraints may inhibit substantially expanded shipments of Western coal on the Great Lakes: (1) the capacity of the Sault Ste. Marie locks; (2) the closing of navigation during the winter months; and (3) the age of the Great Lakes fleet. At present, only one lock at Sault Ste. Marie can handle the more economical 1000-ft collier ships. However, the U.S. Senate has authorized the Army Corps of Engineers to possibly modernize one or more of the other two locks at this critical transfer point. In addition, the Corps of Engineers may extend the allowable vessel length to 1100 feet.

The second limitation on coal shipments is the length of the navigation season. At present, the normal season is 250 days, but the season could potentially be extended to at least 10 months. This would require additional outlays for lock operation and ice-breaking equipment.

The final potential impediment to a rapidly expanded increase in Western coal shipments on the lakes is the age of the Great Lakes fleet. The average age of the entire fleet is over 40 years, with most of the ships unequipped to self-unload coal. Despite these problems, there apparently exists the capacity to build modern, self-unloading ships.

The final leg of the Great Lakes shipment system, that is, port to end user, is the most difficult to assess and likely to experience the greatest constraints. Trucks and railroads are likely to dominate the final distribution system. Trucks are extremely expensive on a per-ton-mile basis and their heavy loads create a number of problems for highway systems. Railroads are less expensive and would probably have few social impacts, but have less flexibility and are slower than trucks. Many of the branch lines that would be needed to serve industrial plants have been abandoned or are in such a poor state of repair that the operation of trains would be severely impaired. A study has been completed at Argonne looking at the relative delivered costs of western and eastern coals to users 50-100 miles inland from a Great Lakes port.¹

5 MARKET REACTIONS TO NEW COAL USE POLICIES AND CONSTRAINTS

The purpose of this section is to simulate the market behavior of coal demanders and suppliers in response to new federal policies that change the economics of coal use. Such federal policies are likely to have complex and even counteracting impacts on industrial fuel choices. On one hand the federal coal conversion mandates to industry will stimulate new demand for coal, but EPA policies on air quality and the new source performance standards (NSPS) are constraining the further use of coal.

A formal model of regional supply and demand for coal has been used to predict the market reactions to these new policy initiatives. To the extent possible, environmental and transportation constraints discussed in the previous section have been quantified and input to the model, along with the total coal demand levels forecast in Section 2. The end results of this procedure are estimates of the market penetration of western coal among industrial users in the Great Lakes Region. This section discusses the results of simulations completed with the Argonne Coal Market model. These simulations were designed to test the effects of alternate environmental standards on the penetration of western coal in the vicinity of five major Great Lakes ports. Model runs were also completed in order to examine the effects of varying lengths of transshipment on the cost competitiveness of western coal around these same ports.

5.1 THE ARGONNE COAL MARKET MODEL

This section is included to give the reader a basic familiarity with the analytical framework used to simulate the market penetration of western coal in the Great Lakes Region. Only a general description of the model is included here. A more complete discussion is found in Reference 10.

The Argonne Coal Market (ACM) model simulates the complex interactions of supply and demand for coals of varying sulfur content. The model is structured to incorporate essential characteristics of coal energy systems, such as these:

- Coal availability
- Coal quality (Btu and sulfur content)
- Total coal demand (industry and utility)
- Disaggregated demand and supply points (spatial detail)
- Federal and state standards for air pollutant emissions
- Extraction costs
- Coal-treatment costs
- Energy penalties for treatment options
- Economic rents
- Variations over time in system behavior
- New and existing contracted demands

Previous work with the model confirms its ability to simulate actual market responses to the changing economic and environmental conditions. For example, it correctly simulated the utility response to the Clean Air Act of 1970. In addition, the model's forecast of the utility responses to the Clean Air Act Amendments of 1977 appear to be quite close to the EPA's independent assessment. However, it should be noted that the model's results are quite sensitive to many of the input assumptions regarding costs, particularly those on the effects on extraction costs of reserve depletion and labor productivity. Thus, the results are subject to some caveats concerning the inherent difficulty of projecting long-term cost conditions for mining.

The following equation defines the quadratic objective function used in the model's optimization algorithm. The object is to minimize:

$$\sum_{i=1}^{NSA} \sum_{j=1}^{NDA} (C_{ij}X_{ij}) + 1/2 \sum_{m=1}^{NSA} Q_m \times \left(\sum_{n=1}^{NDA} X_{mn} \right)^2,$$

where NSA = the number of supply regions,

NDA = the number of demand areas,

C = the cost coefficients obtained by summing transportation costs, environmental control costs, and the values of the supply cost functions at the existing production level,

X = the variables representing levels of coal flows between demand areas and supply regions, and

Q = the matrix of supply function (cost) slopes. The cost per ton increases as production increases.

A primary feature of this formulation is that all consumers in a given demand region face the same extraction price (cost of mining the coal) from a given supply region. Extraction prices increase uniformly for all demand areas as the total deliveries of coal from a given supply region increase, a property of the model that allows it to arrive at proper market clearing prices for specified levels of demand.

Supply functions for coal extraction, which relate costs to output, are expressed as linearly increasing functions for each type of coal. Economic and environmental factors raise the costs of mining and, therefore, the price of coal as production levels increase. Particularly important examples of these cost-modifying factors are wages, labor productivity, the perfection of long-wall mining techniques, mine safety regulations, and land reclamation laws. Nine regional coal-producing areas are considered in the model, each with its own coal quality characteristics and supply schedules.

A sulfur control costing module in the model provides a mechanism for stimulating the level of sulfur removal required to reach state or federal standards. Sulfur emissions from coal combustion are particularly serious pollutants. They can be controlled before combustion by crushing the coal and mechanically washing and screening the particles to separate inorganic sulfur

compounds from the coal. Alternatively, the sulfur problem can be handled after combustion by desulfurizing or "scrubbing" the exhaust flue gas of the boiler or furnace by passing it through a lime or limestone reagent. Although other advanced desulfurization techniques are under development (e.g., solvent refined coal, fluidized bed combustion), only conventional washing and limestone flue gas desulfurization (scrubbing) are considered in the model. Pollution-control costs depend on the supply source and on the coal combustion site because of regional differences in the coal's sulfur compounds and differences in sulfur-dioxide emission regulations in the area of use. Mining, transportation, and sulfur removal costs are combined in the objective function of the equation.

The model has a very high level of geographic detail with respect to the distribution of demand. Up to 98 separate industrial and utility demand points are used. Demands for each region are externally introduced in accordance with prescribed scenarios and include all utility and industrial users of steam coal. Metallurgy coal is excluded because of unique properties that contribute to make it command a much higher price than coal used for its energy content alone, (i.e., steam coal). Coal that must be scrubbed to meet air emissions standards is penalized in the demand constraints to account for energy used in scrubbing.

The model runs in five-year intervals to capture the dynamic behavior of the market system. At the same time, coal contracts, which are typically long-term, are included to capture the inertia of the market system. Moderate time increments make it feasible to characterize coal supply as a linearly increasing function of price. Results from a one-time increment determine the availability and initial price levels of coal for the next time period.

Figure 5.1 presents a structural overview of the Argonne Coal Market model. It shows that the main exogenous inputs to the model are used to calculate incremental demands and supply functions. It also illustrates how a feedback mechanism is used to account for demand and supply dynamics, e.g., supply functions are adjusted after each period to account for resource depletion. Four major outputs are shown: (1) allocations from supply to demand areas; (2) treatment costs for sulfur removal; (3) transportation costs; and (4) extraction costs. These data are generated for all coal flows assigned by the model. Various levels of aggregation may be obtained for both supply and demand data, according to the needs of particular applications.

5.2 SCENARIO ASSUMPTIONS

The Argonne Coal Market model simulates environmental and market conditions around the five Great Lakes ports. This section describes the construction of these scenarios, and specifically how the model parameters were changed to represent alternative EPA policies and transshipment distances.

Implementation of the Clean Air Act Amendments of 1977 posed significant uncertainties for analyzing the market potential of Western coal. The principle regulation that would affect the economics of (and the market demand for) Western coal is the SO₂ removal standard. Three alternative SO₂ standards were defined and simulated in the model:

Fig. 5.1. Flow Diagram of the Argonne Coal Market Model

1. Ninety percent removal of all sulfur naturally found in the coal.
2. An emission limit of 1.0 lb SO₂ /10⁶ Btu of heat input (Scenario A).
3. An emission limit of 1.2 lb SO₂ /10⁶ Btu of heat input (Scenario B).

In addition to environmental variables, the effects of various trans-shipment distances on the demand for Western coal shipped to eastern Great Lakes ports were tested. In these scenarios it was assumed that Western coal was delivered by high-volume collier ships to the Great Lakes ports and then transferred to railcars for volume shipments to end users. The distances of this second rail shipment ranged from 25 to 75 miles.

Table 5.1 shows a summary of the cost variables changed in each transportation scenario. Note that where no change is indicated, base-case assumptions are assumed to apply.

5.3 SIMULATION RESULTS

Tables 5.2 through 5.4 show the market penetration of Western coal given alternative sulfur removal regulations. Under the least stringent case, i.e., the standards that existed prior to the Clean Air Act Amendments of 1977, Western Coal is preferred to Eastern coal in all the major Great Lakes ports studied. This preference was found in both 1985 and 1990 in the immediate vicinity of all five port cities.

This preference for Western low-sulfur coal is based on the coal's relatively low environmental control costs. Prior to the 1977 amendments to the Clean Air Act, new industrial boilers could meet new source performance standards simply by burning low-sulfur coal. This obviated the use of very expensive flue-gas desulfurization technology. While this is essentially the same reason that utilities embraced the use of low-sulfur coal, the

Table 5.1. Comparison of Transportation Costs by Distance from Port City (\$/ton)

Destination	F.O.B. Port	Trans-loading	Final Delivered Cost		
			25 miles	50 miles	75 miles
Buffalo	14.40	1.75	17.99	19.84	21.68
Erie	14.10	1.75	17.69	19.54	21.38
Cleveland	13.80	1.75	17.39	19.24	21.08
Toledo	13.65	1.75	17.24	19.09	20.93
Detroit	13.40	1.75	16.99	18.84	20.68

Table 5.2. Alternative Sources of Coal Preferred by Industries in Vicinity of Great Lakes Ports in 1985, Scenario A^a

Port Area	Distance from Port (rail miles)			
	0	25	50	75
Detroit		Eastern ^b	Eastern	Eastern
Toledo		Eastern	Eastern	Eastern
Cleveland		Eastern	Eastern	Eastern
Erie		Eastern	Eastern	Eastern
Buffalo		Eastern	Eastern	Eastern

^a1.0 lb SO₂/10⁶ Btu, NSPS for industry.

^bEastern coal = Appalachian coal.

Table 5.3. Alternative Sources of Coal Preferred by Industries in Vicinity of Great Lakes Ports in 1985, Scenario B^a

Port Area	Distance from Port (rail miles)			
	0	25	50	75
Detroit	Western ^b (31.0) ^c	Western (36.9)	Western (8.1)	Eastern
Toledo	Western (negligible)	Western (negligible)	Eastern	Eastern
Cleveland	Western (1.7)	Western (3.6)	Eastern	Eastern
Erie	Western (negligible)	Eastern	Eastern	Eastern
Buffalo	Western (negligible)	Western (0)	Eastern	Eastern

^a1.2 lb SO₂/10⁶ Btu of heat input.

^bWestern coal = Northern Great Plains coal. Eastern coal = Appalachian coal.

^cParentheses indicate estimated demand (10⁶ ton).

Table 5.4. Alternative Sources of Coal Preferred by Industries in Vicinity of Great Lakes Ports in 1990, Environmental Scenario B^a

Port Area	Distance from Port (rail miles)			
	0	25	50	75
Detroit	Western ^b (6.1)	Western (7.13)	Eastern	Eastern
Toledo	Western (negligible) ^c	Eastern	Eastern	Eastern
Cleveland	Western (2.5)	Eastern	Eastern	Eastern
Erie	Western (negligible)	Eastern	Eastern	Eastern
Buffalo	Western (negligible)	Eastern	Eastern	Eastern

^a1.2 lb SO₂/10⁶ Btu of heat input.

^bWestern coal = Northern Great Plains coal; Eastern coal = Appalachian coal.

^cParentheses indicate estimated demand.

economic advantages of this sulfur control route are greater for industrial coal users than utilities. Flue-gas desulfurization units are highly capital-intensive and subject to economies of scale. Thus, industrial boilers, which tend to be smaller and used less intensively than utility boilers, will experience higher sulfur control costs per ton of coal burned. Under the 1.2 lb SO₂/10⁶ Btu standard, industrial users of coal will have a strong preference for low-sulfur coal, and western coal will be the least expensive source of supply in the immediate vicinity of all five Great Lakes ports. The relative advantage of western versus Appalachian coal diminishes rapidly with the distance from the port. Rail distances to points surrounding each port city are shown in Figures 5.2-5.5. These maps also show counties with relatively poor ambient air quality, which acts as a constraint to further coal use. As Table 5.4 shows, Detroit is the only port in which western coal is competitive with Appalachian coal more than 25 rail miles from the dockside.

As Table 5.3 shows, the numbers in the columns where western coal is preferred are rough approximations of the BEA area's total coal demand that would be captured by western coal. Even though these estimates are crude, they show that incremental growth in coal demand near the Great Lakes ports is apt to be low. There are two reasons for this: (1) all of these BEA areas have static or declining industrial basis; and (2) the counties near the port cities generally have poor ambient air quality and would, therefore, be unlikely sites for new industrial facilities.

Fig. 5.2. Counties with Utility Coal Use Constrained by Air Quality Considerations, 1985

Fig. 5.3. Counties with Industrial Coal Use Constrained by Air Quality Considerations, 1985

Fig. 5.4. Counties with Utility Coal Use Constrained
by Air Quality Considerations, 1990

Fig. 5.5 Counties with Industrial Coal Use Constrained
by Air Quality Considerations, 1990

Other environmental scenarios were examined. The effects of further tightening the industrial New Source Performance Standards was especially interesting for the analysis. Table 5.3 and 5.4 shows the effects of lowering allowable sulfur emissions to $1.2 \text{ lb SO}_2/10^6 \text{ Btu}$ of heat input. In Scenario B, none of the five ports had any demand for Western coal at a distance of greater than 50 miles from the port in either 1985 or 1990.

6 SUMMARY AND CONCLUSIONS

The industrial coal demand analysis relies on recent U.S. regional forecasts of industrial coal demand. The report focuses on the potential market for western low-sulfur coal in the eight states bordering the Great Lakes, and projects this regional demand to the year 1990. The initial analysis showed that economic attractiveness of western coal shipments appears greatest around the major port cities in the Great Lakes, specifically Buffalo, Erie (Pennsylvania), Cleveland, Toledo, and Detroit; these port cities were studied in detail.

The variations found in other demand forecasts for the industrial sector showed that there might be a large degree of uncertainty between projected and actual realized demands. The DOE Project Independence Evaluation Systems (PIES) model forecasts and the Brookhaven National Laboratory disaggregation of National Energy Plan (NEP) forecasts were selected as the scenarios for industrial coal demand. The DOE-PIES Midrange/Trendlong scenario is the Reference Scenario, representing the level of demand expected under the 1976 air quality regulation and energy policy situation. The NEP scenario represents the changes expected in that demand as a result of the policies embodied in the NEP. Furthermore, analysis of the possible impact of proposed and post-1976 Environmental Protection Agency (EPA) air quality regulations was underway at Argonne and was used in this analysis.

Table 6.1 illustrates the relatively low increase expected in coal use by industries in the Great Lakes states. As coal use by industry has been decreasing historically due to both fuel switching and increased efficiency, the low growth rates actually represent a significant reversal in current trends. Data for the five port city areas were obtained from the Oak Ridge National Laboratory disaggregation of DOE-PIES regional forecasts to Bureau of Economic Analysis (BEA) regions, and from the Brookhaven National Laboratory county-level breakdown of the NEP forecasts. Differences in the forecasting methods required manual adjustments in some instances. The main source of incompatible figures was the difference between coal used for utility and industrial steam generation, coal used for the manufacturing of steel, and total coal use (the sum of the previous two categories). This analysis is based strictly on steam coal, as Western coal is generally not of high enough quality to be used for coking.

The analysis of industrial coal demand included simulation of the supply and demand situation based on the forecast demands by BEA region, the supply/cost relationships for each mining area, heat value of the coals, treatment costs, generalized transportation cost between each part of demand and supply regions, and sulfur content of the coal. The Argonne Coal Market model simulates the flows of coal and estimates the market clearing price for each supply/demand region pair, and is responsive to emission control policies.

The total market for coal for new and existing industrial users range from 28 to 41 x 10⁶ tons of Western coal in 1985, representing a 2 to 4 x 10⁶ ton increase over current demand. This is the maximum volume of Western coal that can be used in the Great Lakes region without regard to price or trans-

Table 6.1. Estimated Industrial Demand for Coal for Steam Generation in Economic Areas Surrounding Port Cities (10^{12} Btu)

Port City	1985		1990	
	Reference Scenario	NEP Scenario	Reference Scenario	NEP Scenario
Buffalo, New York	19.4	20.2	20.1	29.2
Erie, Pennsylvania	10.2	6.1	11.5	8.7
Cleveland, Ohio	119.2	72.5	127.9	89.6
Toledo, Ohio	8.2	20.1	23.0	26.6
Detroit, Michigan	104.6	72.3	114.1	100.3
Total	261.6	191.2	296.6	254.4
Equivalent weights of Western coal (10^6 ton)	15.1	11.1	17.1	14.7
Incremental demand growth from 1974 (10^6 ton Western coal)	2.1	-1.9	4.1	1.7

port limitations. The maximum market is further limited by the cost of a second transshipment at the destination port. There are also problems in meeting air emission restrictions that limit the prime market areas near the port cities, so that a reasonable market for western coal in the Great Lakes states is much smaller than the total forecasted demands. The enhancement of air quality restricts industrial coal users by requiring the use of emission control technology, and by limiting plant location choices based on county classification regarding air quality attainment standards. The EPA is responsible for enforcing regulations developed in response to the Clean Air Act Amendments of 1970 and 1977. Many states were unable to comply with the Amendments set out in 1970, so the 1977 Amendments extended the deadlines for compliance with the regulations, while also requiring updated versions of the New Source Performance Standards (NSPS) regulating air pollutant emissions from stationary sources. The NSPS for coal users has not yet been promulgated; the EPA is proposing 90% removal of sulfur from stack gases, regardless of the initial sulfur content of coal in new boilers.

Under current NSPS, small industrial users of coal are unregulated. The economics of scale in coal combustion are such that the emission control technologies for sulfur removal are cost-effective for large users like electric utilities (\$12-14/ton western coal), but not for many small industrial users (3-4 times utility cost). The small users can adapt to lower-sulfur coal, however, without much capital investment. If the proposed EPA regulation is promulgated, users currently unregulated will be included in the requirement for 90% scrubbing of stack gases. In non-attainment areas (those exceeding the National Ambient Air quality Standards), the further requirement of Lowest Achievable Emission Rate (LAER) will be imposed -- another signif-

ificant cost burden. Thus the users who would find low-sulfur Western coal attractive under existing rules will find it just as expensive as Eastern coal to scrub, in addition to the transportation cost for the longer haul.

The analysis of industrial coal users indicated that the air quality regulations regarding attainment, non-attainment, and prevention of significant deterioration status of counties will constrain the location of industrial plants. This result is significant; it implies that the location decision for the industrial coal users has a new variable to consider. The method for disaggregation of the growth to counties and BEA regions specifies growth in the same areas as existing plants. The reaction of industry may be to locate new plants where none exist now; the constraint would then be overstated.

The scope of this research did not include an analysis of the location decision for coal-burning industries; however, the results indicate that such an analysis is in order. Clarification of location patterns will significantly affect the requirements for transportation facilities to serve the plants.

The transportation network now in place on the Great Lakes does have limitations that affect industrial and utility users. These are: (1) the capacity of the Sault Sainte Marie (Soo) locks; (2) the closing of the lakes in the winter due to ice (except for the St. Lawrence Seaway); and (3) the age of the Great Lakes fleet. The Army Corps of Engineers has indicated that the Soo locks will be modernized, allowing more of the larger vessels and eliminating bottlenecks. Increasing the length of the navigation season requires additional capital-equipment funding for lock operation and icebreaking equipment. More storage piles would still be required at the plants. The 40-year-old vessels in the Great Lakes fleet are not equipped to self-unload coal at transshipment points. Increasing coal traffic would require self-unloaders, in addition to the fact that the many problems of old vessels would lessen the reliability of deliveries.

The rail network from the mines to the transshipment point and from the port city to the plant (for hinterland locations) may both present problems. In general there is sufficient rolling stock, although some rail companies are short of cars now. There may be congestion on longhaul rail rates if the NEP goals for coal use across the nation are achieved. Studies are currently underway to address this problem before the traffic increases occur.

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ACRONYMS AND ABBREVIATIONS

ANL	Argonne National Laboratory
BACT	Best Available Control Technology
BEA	Bureau of Economic Analysis (U.S. Department of Commerce)
DOE	U.S. Department of Energy
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
LAER	Lowest Achievable Emission Rate
NAAQS	National Ambient Air Quality Standards
NEA	National Energy Act
NEP	National Energy Plan
PIES	Project Independence Evaluation System
PL	Public Law
PSD	Prevention of Significant Deterioration
SO ₂	Sulfur Dioxide
TSP	Total Suspended Particulates

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APPENDIX

Appendix Tables A.1 and A.2 show the regional distribution of potential constraints on new industrial coal use, as described in Section 4. The tables assume the Brookhaven disaggregation of the NEP forecast levels of industrial growth in coal demand. The regions that are used are those that were defined in the National Coal Utilization Assessment⁸ to assess the effects of the National Energy Plan.

Table A.1. Regional Results of County-Level Constraint Analysis
for 1985 Industrial Coal Use (New Facilities)

Current County Classification	Northeast		South		Midwest		Rocky Mountain		Northwest		Pacific	
	10 ¹² Btu	% of Total	10 ¹² Btu	% of Total	10 ¹² Btu	% of Total	10 ¹² Btu	% of Total	10 ¹² Btu	% of Total	10 ¹² Btu	% of Total
Attainment	581.6	52.9	932.5	67.5	322.5	31.1	69.3	30.5	32.8	35.6	80.3	35.6
Industrial Coal Impact: PSD Class II and NAAQS maintained	(236.1)	(46.6)	(680.5)	(49.3)	(271.8)	(26.2)	(44.7)	(19.7)	(29.4)	(38.8)	(54.5)	(24.2)
Exceeded for TSP only	(30.1)	(4.2)	(190.5)	(13.8)	(34.6)	(3.3)	(24.6)	(10.8)	(3.4)	(4.5)	(25.8)	(11.4)
Exceeded for SO ₂ only	(6.9)	(1.0)	(16.4)	(1.2)	(11.1)	(1.1)	(0)	(0)	(0)	(0)	(0)	(0)
Exceeded for TSP and SO ₂	(8.5)	(1.1)	(45.1)	(3.2)	(5.0)	(0.5)	(0)	(0)	(0)	(0)	(0)	(0)
PSD Class I	1.8	0.3	30.6	2.2	0.4	0.1	39.0	17.4	30.0	39.6	118.9	52.7
Nonattainment - TSP only	174.8	24.2	355.7	25.7	312.0	30.3	99.4	43.8	12.9	17.1	19.9	8.8
Nonattainment - SO ₂ only	2.0	0.3	6.2	0.5	57.6	5.6	6.8	3.0	0	0	2.2	1.0
Nonattainment - SO ₂ and TSP	<u>150.8</u>	<u>22.3</u>	<u>57.0</u>	<u>4.1</u>	<u>340.5</u>	<u>32.9</u>	<u>12.1</u>	<u>5.3</u>	<u>0</u>	<u>0</u>	<u>4.4</u>	<u>1.9</u>
TOTAL	721.0	100.0	1,382.0	100.0	1,035.0	100.0	227.2	100.0	75.7	100.0	225.7	100.0

Table A.2. Regional Results of County-Level Constraint Analysis for 1990
Industrial Coal Use (New Facilities)

Current County Classification	Northeast		South		Midwest		Rocky Mountain		Northwest		Pacific	
	10 ¹² Btu	% of Total	10 ¹² Btu	% of Total	10 ¹² Btu	% of Total	10 ¹² Btu	% of Total	10 ¹² Btu	% of Total	10 ¹² Btu	% of Total
Attainment	566.2	54.5	1,353.3	69.5	389.9	27.6	114.5	29.1	52.8	43.4	118.0	35.9
Industrial Coal Impact: PSD Class II and NAAQS maintained	(468.2)	(45.1)	(1,005.0)	(51.6)	(318.1)	(22.5)	(73.7)	(18.7)	(46.6)	(38.5)	(54.8)	(16.7)
Exceeded for TSP only	(58.2)	(5.6)	(243.6)	(12.5)	(46.8)	(3.3)	(40.8)	(10.4)	(6.0)	(4.9)	(63.2)	(19.2)
Exceeded for SO ₂ only	(19.8)	(1.9)	(41.3)	(1.3)	(18.0)	(1.3)	(0)	(0)	(0)	(0)	(0)	(0)
Exceeded for TSP and SO ₂	(20.0)	(1.9)	(63.4)	(2.1)	(7.0)	(0.5)	(0)	(0)	(0)	(0)	(0)	(0)
PSD Class I	2.6	0.3	45.5	2.3	1.7	0.1	67.0	17.1	46.0	38.0	169.9	51.7
Nonattainment - TSP only	241.5	23.2	463.4	23.8	446.2	31.6	174.7	44.5	21.8	18.0	31.8	9.7
Nonattainment - SO ₂ only	3.0	0.3	9.1	0.5	83.3	5.9	12.1	3.1	0	0	2.8	0.9
Nonattainment - SO ₂ and TSP	<u>225.7</u>	<u>21.7</u>	<u>76.8</u>	<u>3.9</u>	<u>490.4</u>	<u>34.8</u>	<u>24.4</u>	<u>6.2</u>	<u>0.8</u>	<u>0.6</u>	<u>5.8</u>	<u>1.8</u>
TOTAL	1,039.0	100.0	1,948.0	100.0	1,411.5	100.0	392.7	100.0	121.2	100.0	328.3	100.0